

Decision 17-06-027 June 29, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee
the Resource Adequacy Program,
Consider Program Refinements, and
Establish Annual Local and Flexible
Procurement Obligations for the 2016 and
2017 Compliance Years.

Rulemaking 14-10-010
(Filed October 16, 2014)

**DECISION ADOPTING LOCAL AND FLEXIBLE CAPACITY OBLIGATIONS
FOR 2018 AND REFINING THE RESOURCE ADEQUACY PROGRAM**

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**DECISION ADOPTING LOCAL AND FLEXIBLE CAPACITY OBLIGATIONS FOR
2018 AND REFINING THE RESOURCE ADEQUACY PROGRAM**

Summary

This decision adopts local and flexible capacity obligations for 2018 applicable to Commission-jurisdictional electric load serving entities, adopts an Effective Load Carrying Capacity approach to determining the capacity value of wind and solar resources, and makes other changes to the Resource Adequacy program.

The local procurement obligations are based on annual studies of local capacity and flexible capacity requirements performed by the California Independent System Operator (CAISO) for 2018 which seek to ensure that each part of the CAISO controlled grid, including those parts with transmission constraints, have access to sufficient generating capacity to meet the local need. The total local capacity requirements recommended by the CAISO, and those adopted for all local areas, increased from the prior year. The total of all local areas increased from 24,549 megawatts (MW) in 2017 to 25,207 MW in 2018, the “existing” capacity increased from 23,643 MW in 2017 to 24,400 MW in 2018.

The CAISO’s recommended system-wide flexible capacity requirement is also adopted. The Commission-jurisdictional 2018 flexible capacity requirements range from 10,156 MW (July 2018) to 14,611 MW (December 2018). The flexible capacity needs increased from those identified by the CAISO and adopted by the Commission for 2017, which ranged from 9,292 MW (August 2017) to 14,426 MW (November 2017). The increase is primarily due to the increasing penetration of solar resources, which in turn affects the net load ramp.

This proceeding is closed.

1. Background

Public Utilities Code Section 380¹ requires that “the commission, in consultation with the California Independent System Operator (CAISO or ISO), shall establish resource adequacy requirements for all load-serving entities.” The statute establishes a number of objectives for the Commission to achieve with the resource adequacy (RA) program, including development of new generating capacity and retention of existing generating capacity, equitable allocation of the cost of generating capacity, and minimization of enforcement requirements and costs. Section 380(j) defines “load serving entities” (LSEs) for purposes of this section as “an electrical corporation, electric service provider, or community choice aggregator.”

Based on the statutory language, the Commission's RA program and its requirements apply to all LSEs under our jurisdiction. Certain small or multi-jurisdictional LSEs are subject to different RA requirements which are more appropriate to their situations than those described in this order.

Additional information on the procedural history of this proceeding is set forth in the October 16, 2014 Order Instituting Rulemaking for this proceeding, and Decisions (D.) 15-06-063 and D.16-06-045 provide additional detail on the procedural and substantive background of this proceeding to date.

A Scoping Memo for this phase of the RA proceeding was issued on September 13, 2016. The Scoping Memo identified the issues to be addressed, and set forth a schedule incorporating an extensive series of proposals, workshops, and comments on those issues. This decision addresses the issues identified in that Scoping Memo.

¹ All subsequent statutory references are to the Public Utilities Code unless stated otherwise.

2. Issues Before the Commission

The September 13, 2016 Scoping Memo identified four primary issues to be addressed: local and flexible RA requirements for 2018, a durable Flexible Capacity Requirement (FCR), multi-year RA requirements, and Effective Load Carrying Capacity (ELCC) of wind and solar resources. (Scoping Memo at 2.)

In addition, other issues were raised, and are addressed here in the following sections: Fast Dispatch of Slow Response Resources, Clarify Definition of “Dispatchable,” Removal of the Path 26 Constraint, Weather Sensitive Demand Response, Maximum Cumulative Capacity Buckets, Existing Demand Side Load Impacts, Seasonal Local Resource Adequacy, and Local Resource Counting Issues.

Parties were provided opportunities to present additional issues and proposals to the Commission; as a result, numerous other issues were raised. Because of their number and complexity, and a wide variation in the adequacy of record support, not all of these issues are specifically addressed in this decision. Issues and proposals not expressly adopted by this decision are not approved, but that rejection-by-silence is without prejudice, and those issues or proposals may be raised again as appropriate in future Commission proceedings.

3. Local Capacity Requirements (LCR) for 2018

The local RA program was first adopted in D.06-06-064. That decision adopted a framework for local RA and established local procurement obligations for 2007 only. D.07-06-029, D.08-06-031, D.09-06-028, D.10-06-036, D.11-06-022, D.12-06-025, D.13-06-024, D.14-06-050, D.15-06-063 and D.16-06-045 established local procurement obligations for 2008 through 2017, respectively. The RA program has been refined each year since 2007. The local RA program and associated regulatory requirements adopted in those decisions continue in effect

for 2018 and thereafter until changed, subject to the 2018 LCRs and procurement obligations adopted by this decision.

The RA program includes both “system” and “local” RA requirements. Each LSE must procure sufficient RA capacity resources to meet both obligations. “System” RA requirements are calculated based on an LSE’s “system” peak load plus a 15% planning reserve margin. “Local” RA requirements are calculated based on the CAISO’s annual LCR studies, and are allocated to each individual Commission-jurisdictional LSE by the Commission. Each LSE must then procure sufficient RA capacity resources in each local area to meet their obligations.

D.06-06-064 determined that a study of LCR, performed by the CAISO, would form the basis for this Commission’s local RA program. The CAISO conducts its LCR study annually, and this Commission resets local procurement obligations each year after a review of the CAISO’s LCR recommendations. This year, the CAISO’s final LCR study for 2018² was received by the Commission on May 1, 2017. The CAISO states that the assumptions, processes and criteria used for the LCR study were discussed and recommended in a stakeholder meeting, and on balance mirror those used in the 2007 through 2017 LCR studies. The CAISO identified and studied capacity needs for the same ten local areas as in previous studies: Humboldt, North Coast/North Bay, Sierra, Greater Bay, Greater Fresno, Big Creek/Ventura, Los Angeles (LA) Basin, Stockton, Kern, and San Diego/Imperial Valley.

The local requirements increased considerably for the San Diego/Imperial Valley local area from previous years, although the CAISO explained

² The CAISO refers to its process as its Local Capacity Technical Analysis.

that the 3,570 megawatt (MW) requirements for 2017 should have been 4,635 MW. Additionally, the CAISO introduced two sensitivities in the draft final results for the San Diego/Imperial Valley local area and the San Diego sub-area.

CAISO's recommended 2018 LCR are summarized in the following table.³ The 2017 LCR is provided for comparison.

³ Quantities for San Diego/Imperial Valley (and corresponding totals) were modified in response to comments on the proposed decision filed by SDG&E.

2018 Local Capacity Requirements			
	2018 LCR Need Based on Category C with Operating Procedure		
Local Area Name	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	169	0	169
North Coast / North Bay	634	0	634
Sierra	1826	287*	2113
Stockton	398	321*	719
Greater Bay	5160	0	5160
Greater Fresno	2081	0	2081
Kern	453	0	453
LA Basin	7525	0	7525
Big Creek/ Ventura	2321	0	2321
San Diego/ Imperial Valley	3833	199	4032
Total	24400	807	25207
* CAISO note: No local area is “overall deficient.” Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency, the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.			
** CAISO note: Since “deficiency” cannot be mitigated by any available resource, the “Existing Capacity Needed” will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.			
*** CAISO note: TPL 002 Category B is generally equivalent to TPL 001-4 Category P1. TPL 003 Category C is generally equivalent to TPL 001-4 P2 through P7. Current LCR study report is compliant with existing language in the ISO Tariff Section 40.3.1.1 Local Capacity Technical Study Criteria to be revised at a later date.			
****CAISO note: In the 2017 LCR report, the San Diego-Imperial Valley study and the LA Basin-San Diego overall study had inconsistent assumptions regarding LA Basin resources, resulting in lower LCR value reported for the overall San Diego-Imperial Valley LCR area (3,570 MW). This value should have been reported as 4,635 MW based on the 2017 LCR requirements for the LA Basin and San Diego subarea.			

2017 Local Capacity Requirements			
	2017 LCR Need Based on Category C with Operating Procedure		
Local Area Name	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	157	0	157
North Coast / North Bay	721	0	721
Sierra	1731	312*	2043
Stockton	402	343*	745
Greater Bay	5385	232*	5617
Greater Fresno	1760	19*	1779
Kern	492	0	492
LA Basin	7368	0	7368
Big Creek/ Ventura	2057	0	2057
San Diego/ Imperial Valley	3570	0	3570
Total	23643	906	24549
* CAISO note: No local area is “overall deficient.” Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency, the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.			
** CAISO note: Since “deficiency” cannot be mitigated by any available resource, the “Existing Capacity Needed” will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.			
*** CAISO note: TPL 002 Category B is generally equivalent to TPL 001-4 Category P1. TPL 003 Category C is generally equivalent to TPL 001-4 P2 through P7. Current LCR study report is compliant with existing language in the ISO Tariff Section 40.3.1.1 Local Capacity Technical Study Criteria to be revised at a later date.			

4. Flexible Capacity Requirements (FCR) for 2018

D.13-06-024 and D.14-06-050 adopted a flexible capacity requirement to begin in 2015 and defined guidelines for its implementation. D.15-06-063 also adopted FCR for 2016. D.13-06-024 recognized a need for flexible capacity in the RA fleet and defined flexible capacity need:

“Flexible capacity need” is defined as the quantity of resources needed by the CAISO to manage grid reliability during the greatest

three-hour continuous ramp in each month. Resources will be considered as “flexible capacity” if they can sustain or increase output, or reduce ramping needs, during the hours of “flexible need.”⁴

This year, the CAISO’s final Flexible Capacity Needs Assessment for 2018 was received by the Commission on May 1, 2017. The CAISO changed the must-offer hours for “peak” and “super peak” resources from noon - 5 pm to 3 - 8 pm for May - September, and from 3 - 8 pm to 2 -7 pm for January - April and October - December.

Based on its analysis, the CAISO identified the maximum flexible capacity needs for each month of 2018, as shown on the table below. The flexible capacity needs are greatest in non-summer months and range from 10,908 MW (July 2018) to 15,743 MW (December 2018). The flexible capacity needs increased from those identified for 2017, which in turn were greater than 2016 needs. Much of this change was due to a continuing increase in solar production in each year’s study. As illustrated in the table below, most of the flexible capacity needs are allocated to CPUC-jurisdictional load serving entities (ranging from 91% in February to 97% in April).

⁴ D.13-06-024 at 2.

2018 Flexible Capacity Needs

NOTE: All numbers are in Megawatts	CAISO System Flexible Requirement	CPUC Flexible Requirement	CPUC		
			Category 1 (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	13,415	12,437	4,806	7,010	622
February	14,409	13,151	5,081	7,413	658
March	13,435	12,801	4,946	7,215	640
April	12,272	11,876	4,589	6,694	594
May	13,095	12,308	6,746	4,946	615
June	11,497	10,688	5,858	4,295	534
July	10,908	10,156	5,567	4,081	508
August	11,219	10,789	5,914	4,336	539
September	14,248	13,468	7,383	5,413	673
October	14,271	13,291	5,135	7,491	665
November	14,505	13,569	5,243	7,648	678
December	15,743	14,611	5,646	8,236	731

In addition, the CAISO divides flexible capacity needs into three categories. These categories are defined based on the CAISO's assessment of the different types of flexible capacity needed. Specifically, in the "flexible resource adequacy criteria and must offer obligation" stakeholder initiative, the CAISO adopted the following flexible capacity categories:⁵

Category 1 (Base Flexibility): Operational needs determined by the magnitude of the largest 3-hour secondary ramp.

⁵ For further background on these categories, see D.14-06-050.

Category 2 (Peak Flexibility): Operational needs determined by the difference between 95% of the maximum 3-hour net-load ramp and the largest 3-hour secondary net-load ramp.

Category 3 (Super-Peak Flexibility): Operational needs determined by 5% of the maximum 3-hour net-load ramp of the month.

While the CAISO has identified flexible capacity needs by category and by month, the CAISO established the requirements on a seasonal basis. Accordingly, the CAISO proposes percentage maximum or minimum limits for different categories of flexible resources applicable to summer (May - September) and winter (all other months). The application of these percentage limits on categories of flexible resources to Commission jurisdictional entities is shown in the table above.

5. Process and Timing Issues

5.1. Capacity Requirement Study Timing

In D.16-06-045, this Commission stated:

In most years, the LCR Study and FCR Study results have been uncontested. Even in the event that the results of the LCR and FCR Studies are non-controversial, the timelines of recent RA proceedings (Studies in late April or early May, proposed decision in mid- or late-May, final decision in June) leaves very little time for review of the Studies' results by the CPUC and parties in the RA proceeding.

In order to ensure that we are able to provide due process to all parties, we request that in future LCR and FCR studies, the CAISO promote an open and transparent process. In particular, we request that the CAISO adhere to the following guidelines:

- All draft studies should be posted to the CAISO website when they are released,

- Posted drafts should remain publically accessible for the duration of the process,
- All comments on draft studies should be posted to the CAISO website soon after they are received,
- If necessary due to confidentiality concerns, commenting stakeholders should be encouraged to submit public and confidential versions of their comments,
- Draft and final studies should describe and address the impact of any data that was not available to the CAISO to perform the study,
- Work papers supporting the final studies should be shared with Energy Division staff as necessary to implement the RA program,
- The final studies should include a response to comments,
- The final studies should be filed and served in the then-current RA proceeding by April 15 of each year, unless otherwise scheduled by the ALJ or scoping memo, and
- The final LCR study should include an explanation of the role of DR, including busbar level data provided by the utilities.
(D.16-06-045 at 16-17.)

Most of the guidelines above were met, although the CAISO introduced two sensitivities late in the process, providing little time for review.

In addition, a number of parties raised concerns with process and timing. Pacific Gas and Electric Company (PG&E) stated:

This year, there has been little time to review the Final 2018 LCR Analysis relative to previous drafts, and to develop comments for the Commission. The CAISO was not able to comply with the Commission's adopted timeline to publish the final report. PG&E requests that the Commission and the CAISO develop a mutually acceptable timeline for future studies that provides at approximately two weeks for comment on the CAISO's final report, and provides for reply comments. Development of the study consistent with the

Commission's adopted timeline for this year would have been consistent with this request. [...]

PG&E also encourages the CAISO to be as transparent as possible with respect to the assumptions underlying the various local transmission studies it conducts. PG&E recognizes that it is a challenging, often iterative process to determine the final study parameters for each local study. However, it is difficult to provide informed feedback to the CAISO and the Commission if study assumptions are not clearly set out. (PG&E May 5, 2017 Comments at 2-3.)

The Center for Energy Efficiency and Renewable Technologies (CEERT) similarly argues that: "[T]he current complexity and lack of transparency continue to adversely impact any assessment of the LCR and FCR requirements..." (CEERT May 5, 2017 Comments at 3.) Specifically, CEERT states:

In CEERT's Opening Comments on the Draft 2018 LCR and Draft 2018 FCR Studies, CEERT expressed concern that the "CAISO calculates the Local Capacity Requirements (LCR) need by a complex, but completely transparent process whose mere outline requires some twenty-five pages to describe" and that, while "the FCR need" calculation methodology is transparent, "the underlying metric and the resources deemed qualified to satisfy that need are anything but clear," including "what the incremental cost of FCR actually is or what resources are actually supplying flexibility in real time." [fn. omitted] The Final 2018 LCR Study and Final 2018 FCR Study, for which links were served by CAISO to the service list in this proceeding on May 1, 2015, do not provide any greater clarity for either study.

Thus, not only has a very limited amount of time (4 days) been allowed to review these final studies, but neither includes redlined revisions, so it is nearly impossible to quickly determine what changes, if any, have been made and whether those changes are meaningful or responsive to comments by parties. (Id. at 2-3.)

Significant for purposes of this proceeding is the fact that the final LCR and FCR studies were not filed and served in this proceeding by April 15, but rather were filed and served on May 1. Given the need for the CPUC to provide a timely decision adopting local and flexible capacity procurement obligations for load-serving entities, this delay creates serious problems.

As a result of the CAISO's inability or refusal to meet the Commission's deadline, neither the parties to this proceeding nor the Commission have had an adequate opportunity to address issues raised by the final LCR and FCR studies. The Commission's decision approving the LCR and FCR studies, and imposing their corresponding procurement obligations on the load-serving entities, becomes little more than a "rubber stamp" of the CAISO's conclusions. This is unacceptable to the Commission, and going forward the Commission will explore ways to resolve this problem.

For purposes of the current studies provided to the Commission on May 1, 2017, the Commission is approving procurement based upon those studies, but may further examine the inputs, processes, and results of those studies in this proceeding or a successor proceeding.

5.2. Timelines for Publishing Capacity Listings

PG&E recommends that the Commission and the CAISO revise the current annual RA timeline to ensure that the draft Net Qualifying Capacity (NQC) and Effective Flexible Capacity (EFC) lists are published by July 1 of each year, to be applicable for the following compliance year. (PG&E February 24, 2017 Final Proposal at 12-13.)

PG&E describes the process involved:

The initial step in the process of determining the NQC for a resource for the upcoming resource adequacy year is for the Commission (or

relevant local regulatory authority (LRA)) to establish a QC value based on the adopted methodology for that resource type. [footnote omitted] The Commission/LRA then provides the QC values to the CAISO. Currently, the QC values are due to the CAISO on June 1 of every year.

The CAISO then transforms the QC value for each resource into an NQC. To do this, among other things the CAISO takes into account the deliverability of the resource. The CAISO then uses the NQC, along with other inputs, to determine each resource's EFC value. (Id. at 12.)

PG&E notes that the previously-established schedule for this process has not been followed in recent years, resulting in inadequate time for interested parties to provide comments on the NQC and EFC values. (Id.)

Other parties support PG&E's proposal (*see, e.g.,* AReM March 10, 2017 Comments at 6). The CAISO acknowledges the interest of the parties in establishing firm deadlines for the issuance of Qualifying Capacity values, but recommends that: "[T]he Commission provide the Qualifying Capacity list to the CAISO by June 1 instead of attempting to establish new rules in this proceeding." (CAISO January 13, 2017 Comments at 12.)

We encourage the Commission's Energy Division to work cooperatively with the CAISO, and to provide the CAISO with the Qualifying Capacity list by June 1 to assist the CAISO to publish the NQC and EFC lists by July 1 of each year.⁶

⁶ Because June 1 is earlier than the date the Commission would vote on a final RA decision, Energy Division would only be providing staff-recommended or "draft" values, which could be changed in the Commission decision.

5.3. Energy Division Load Forecasting Process

In D.16-06-045, the Commission noted that parties had expressed concern about the load forecasting process used by Energy Division, with a focus on transparency and consistency. (D.16-06-045 at 49.) In response, the Energy Division posted a report to its website in October 2015, held workshops on February 18, 2016 and March 25, 2016, and posted an additional report to its website on May 12, 2016. The Commission found: “We note that the document posted by the Energy Division on May 12, 2016 addresses many of the questions and topics of concern raised by stakeholders.” (Id. at 52.) But since parties had not commented on the document, the Commission directed the Energy Division to hold an additional workshop and obtain party comments. On August 31, 2016, Energy Division redistributed the May 12, 2016 document, held an all-day workshop on the document on October 27, 2016, and provided an opportunity for parties to provide comments.⁷ This appears to be adequate disclosure and discussion of Energy Division’s load forecasting process, and Energy Division may continue to perform load forecasting in a manner consistent with this publicly-disclosed process.

6. Durable Flexible Capacity Requirement

As noted in the Scoping Memo, the Commission adopted an “interim” FCR program in D.13-06-024 and D.14-06-050, which remains in place now. (Scoping Memo at 4.) At the time the Scoping Memo was issued, the record was insufficient to support adoption of a “durable” (as opposed to “interim”) flexible capacity requirement, and accordingly the Scoping Memo posed a number of

⁷ Two parties – Shell and CLECA – submitted comments.

questions in order to provide an opportunity to further build the record on this issue. (Id. at 5.)

While additional information was obtained through this process, there is a general consensus that it is not possible, or at least not advisable, to adopt a durable flexible capacity requirement at this time. (See, e.g., PG&E's January 13, 2017, Comments at 3.) The CAISO agrees, stating that: "[T]here is insufficient time to implement significant changes to the flexible RA program in this cycle." (CAISO January 13, 2017, Comments at 2.) TURN similarly stated: "The Commission's and CAISO's former ambitions to implement a "durable" flexible capacity program will not be realized in calendar year 2017 in time for implementation in the 2018 RA compliance year." (TURN January 13, 2017, Comments at 7.)

Accordingly, we do not adopt a durable flexible capacity requirement at this time. The current interim FCR remains in effect for 2018.

7. Multi-year Resource Adequacy Requirements

In response to an initial proposal from the Independent Energy Producers Association (IEP), the Scoping Memo in this proceeding noted that "there may be benefits to a coordinated consideration of multi-year RA." (Scoping Memo at 8.) The Scoping Memo further directed Energy Division Staff to issue a report addressing the status of forward capacity procurement to help inform the parties and the record of this proceeding. (Id. at 8-9.)

The Scoping Memo noted, however, that the Commission recently held that a multi-year RA requirement should only be considered after the development of a durable FCR program. (Id. at 8, citing D.16-01-033.) In addition, numerous parties oppose the adoption of a multi-year RA requirement at this time. (See, e.g., CEERT Final Comments at 2, ORA Final Comments at 1-3,

SDG&E Final Comments at 6.) Since we are not adopting a durable FCR program at this time (which, according to the Scoping Memo in this proceeding, is a prerequisite for a multi-year RA requirement), we do not adopt a multi-year RA requirement here, nor do we address the substantive issues relating to such a requirement. In future RA proceedings the Commission may re-examine whether a durable FCR program should continue to be a prerequisite to adoption of a multi-year RA requirement.

IEP also proposed that the Commission adopt “an annual reporting obligation for all jurisdictional LSEs showing each LSE’s contracted RA capacity for 1, 3, and 5 years forward.” (IEP February 24, 2017, Proposal at 15.) Under IEP’s proposal, the Commission would use this information to issue an annual public summary of multiyear RA capacity procurement. (Id.)

It is not clear at this time that the potential benefits of IEP’s proposal are significant enough to justify the additional burden. (*See, e.g.,* SDG&E March 10, 2017, Comments at 5-6; Shell March 10, 2017, Comments at 2-4; PG&E February 15, 2017, Comments at 2.) LSEs are already required to report contract start and end dates in their RA compliance filings. In addition, the Commission’s Energy Division is currently authorized to: “...gather and disseminate information regarding expected electric resource availability and the forward contracting of such resources, and make such information available to the public.” (D.16-01-033 at 1 and 9.) Energy Division has already issued two such reports, and we encourage continued monitoring and reporting on this issue. Accordingly, we do not adopt IEP’s more rigidly-defined multi-year reporting requirement at this time.

8. Effective Load Carrying Capacity (ELCC)

Public Utilities Code Section 399.26(d) directs this Commission to:

... determine the effective load carrying capacity of wind and solar energy resources on the California electrical grid. The Commission shall use those effective load carrying capacity values in establishing the contribution of wind and solar energy resources toward meeting the resource adequacy requirements established pursuant to Section 380.

This decision implements Effective Load Carrying Capacity (ELCC), which this Commission has previously described:

ELCC is a statistical modeling approach to determine the capacity value of different resources relative to “perfect capacity.”^[8] For example, if removing 100 MW of solar resources from the grid and replacing it with 50 MW of perfect capacity results in no change in the Loss of Load Expectation (LOLE), then the ELCC of the solar resources would be 50%. (D.16-06-045 at 17.)

Implementation of ELCC has proven to be lengthy and complex. Over time, the Commission’s Energy Division and the parties to this proceeding (and its predecessors) have issued, analyzed, and refined proposals to implement ELCC. In 2016, Energy Division staff developed a proposal for measuring ELCC of wind and solar resources for purposes of the RA program; that proposal was addressed in D.16-06-045, which stated: “Parties generally agree that, although there has been great progress in ELCC efforts, ELCC should not be implemented for 2017.” (D.16-06-045 at 18.)

⁸ Perfect capacity refers to fictional generators created in the model that have perfect capabilities, such as zero forced and maintenance outage rates and zero startup times, and serve as a standard against which to compare real existing generators.

Since that time, Energy Division staff developed a methodological process, including updated data inputs and improvements to the underlying Energy Division dataset to incorporate revised inputs. On December 16, 2016 Energy Division and parties to this proceeding issued proposals for implementing monthly wind and solar ELCC for the 2018 RA compliance year. The two proposals that gathered significant support among the parties were those of Energy Division and Calpine Corporation (Calpine). (*See, e.g.,* CLECA March 10, 2017 Comments at 3.) Energy Division and the parties participated in a workshop on February 14, 2017, and final proposals were submitted on February 24, 2017. Energy Division and Calpine brought their proposals significantly closer together, and Energy Division actually issued two proposals, with the second one being a modification of the first.

In general, the Energy Division and Calpine approaches are quite similar. There are some differences in the steps used to calculate monthly ELCC, which are detailed in Appendix A. While Energy Division and Calpine used different models in reaching their result, and each model has its potential advantages and disadvantages, we are not directing the use of a particular model for future ELCC determinations. At this initial implementation stage of ELCC, it is too early to determine the ideal model to use, and we want to allow flexibility going forward to allow the most appropriate model to be used.

Energy Division notes that moving from the current exceedance method to ELCC results in a “...notable decrease in RA capacity credit given to solar generators...,” and accordingly Energy Division’s second proposal seeks to ease that transition. (Energy Division February 24, 2017, Proposal at 16.) Because the relatively low ELCC value for solar can be partially ascribed to the addition of behind-the-meter solar to the grid (even though behind-the-meter solar does not

receive RA credit), Energy Division's second proposal is designed to back out the effect of behind-the-meter solar from the ELCC calculation. (Id.)

PG&E recommends going to an ELCC approach, but with a two year transition period in order to soften the change, and to allow LSE's to adjust to "the anticipated decrease in RA capacity from wind and solar resources during the peak months." (PG&E February 24, 2017, Proposal at 4.)

We agree with PG&E and other parties that moving to an ELCC approach such as Calpine's proposal or Energy Division's first proposal could result in an overly abrupt and significant change in RA values, particularly of solar resources, and would be unnecessarily disruptive. Both Energy Division's second proposal and PG&E's approach address this issue, but we believe that Energy Division's second proposal, which seeks to remove the influence of behind-the-meter solar, has a stronger analytical basis, and is less of a stopgap measure than PG&E's proposal. Accordingly, we adopt Energy Division's second proposal, and the numbers resulting from that proposal are the approved values for 2018, as set forth in Appendix A. Going forward, the process used to calculate monthly ELCC values will be subject to changes, improvements and refinements as needed.

9. Other Issues

A number of other issues were raised in the course of this proceeding, with some being addressed by the parties in more detail than others. Many of these issues are still under development, or are otherwise not quite ready for implementation. As this proceeding (or a successor proceeding) continues, the Commission may address these issues. For some issues, it may be helpful to create working groups or conduct workshops or other informal processes, so that

the parties and the Commission's Energy Division can continue to develop and refine implementable proposals for the Commission's consideration.

9.1. Fast Dispatch of Slow Response Resources

SCE recommends that, in light of the possibility of the implementation of a 20-minute response time requirement for DR resources to receive local RA credit, it is important to calculate the response capability of resources that need more than 20 minutes to reach their full capacity. According to SCE,

[I]t is possible for DR Resources with program mandated response times greater than 20 minutes to reliably provide energy reductions to the CAISO in a 20 minute time frame. In other words, a program requiring a full response within a longer than 20 minute time frame will have a "ramp rate" that can result in a significant portion of the program MW being reliably delivered within the 20-minute timeframe. (SCE December 16, 2016 Preliminary Phase 3 Proposal at 13.)

As a result, SCE argues that if a 20-minute requirement is adopted, the portion of a slow response resource that can reliably respond within 20 minutes should receive local RA credit. (Id.) A number of parties support this proposal, including PG&E (PG&E January 13, 2017 Comments at 12), California Large Energy Consumers Association (CLECA) (CLECA January 13, 2017 Comments at 17) and NRG (NRG January 13, 2017 Comments at 15).

While we are not adopting a 20-minute requirement here, the idea underlying SCE's proposal is consistent with this Commission's determination in D.16-06-045 that: "[T]he portion of a resource that reliably responds within the required period (even if less than 100%) should be counted for local RA." (D.16-06-045 at 36.) We reiterate that determination here, but note that SCE (and other parties) acknowledge that further work in this area (coordinated with the CAISO) is necessary.

9.2. Clarify Definition of “Dispatchable”

PG&E recommends a clarification of the definition of the terms “dispatchable” and “non-dispatchable,” and identified a number of issues that can arise because there is currently not a clear definition of those terms. (PG&E February 24, 2017 Final Proposal at 20-21.)

The CAISO agrees that the term “dispatchable” is not clearly and definitively defined, which creates confusion. The CAISO notes that the Commission and CAISO use the term “dispatchable” differently, and recommends a joint Commission-CAISO workshop to discuss the uses and meanings of the term “dispatchable,” and to establish a common vocabulary. (CAISO January 13, 2017 Comments at 12.)

PG&E raises a valid concern, and the CAISO recommends a good way to address that concern. Accordingly, the Commission’s Energy Division may either hold a joint workshop with the CAISO or establish a working group to address this issue.⁹

9.3. Removal of the Path 26 Constraint

PG&E proposes that the Path 26 constraint be removed from the resource adequacy program; PG&E argues that this Commission-established constraint on Path 26 is no longer needed, and is unfair. (PG&E February 24, 2017 Final Proposal at 17-19.)

The CAISO opposes PG&E’s proposal: “Contrary to PG&E’s recommendation, the Path 26 counting constraint remains relevant and necessary

⁹ If the Commission’s Energy Division holds a joint workshop, Energy Division may notice this workshop in coordination with the CAISO. The workshop may be held after this proceeding is closed. If the workshop is held prior to a prehearing conference in a successor proceeding, notice of the workshop should be provided to the service list of this proceeding.

as a planning and procurement tool for the same reasons it was originally intended.” (CAISO March 10, 2017 Comments at 5-7.) The CAISO argues that PG&E’s arguments are erroneous and mischaracterize the CAISO’s position. (Id.)

Other parties, however, are cautiously supportive of PG&E’s proposal, and believe it should be studied further. Southern California Edison Company (SCE), for example, states:

SCE recommends that the Commission and CAISO study the option to remove the Path 26 constraint. The Path 26 constraint limits the resources load-serving entities (“LSEs”) are allowed to procure for RA and could result in LSEs having to procure different resources than they otherwise would without this constraint. If this constraint is no longer needed, then it is artificially placing restrictions on resource procurement and could be increasing costs for customers. (SCE March 10, 2017 Comments at 6.)

Alliance for Retail Energy Markets (AReM) took a similar position:

AReM is intrigued by PG&E’s proposal to remove the Path 26 constraint from the Commission’s RA program. Ensuring compliance with the Path 26 constraint adds complexity to the already complex process of procuring RA and making the annual and monthly showings. AReM supports additional evaluation of this proposal, and, should that additional evaluation show that the Path 26 constraint is no longer needed for reliability purposes, it should be removed. (AReM January 13, 2017 Comments at 4.)

This proposal is worth considering more carefully; accordingly we direct the creation of a working group to study this issue, particularly whether implementing PG&E’s proposal would cause any reliability issues. The working group will submit its analysis and recommendation to the proceeding considering 2019 RA compliance.

9.4. Weather Sensitive Demand Response

San Diego Gas & Electric Company (SDG&E) presented a general proposal to consider how to integrate weather sensitive demand response (DR) into the CAISO markets, along with a more specific proposal that non-utility weather sensitive DR resources be permitted to choose to utilize the Load Impact Protocols (LIPs) methodology instead of the current registered capacity methodology. (SDG&E December 16, 2016 Proposal at A-1 – A-3.) According to SDG&E, the current approach may be problematic for DR resources that have a load reduction that varies predictably with weather, such as curtailment of air conditioning. (Id.) SDG&E also suggests the use of a working group on this issue, that considers how to integrate weather sensitive DR into the CAISO markets. (Id.)

PG&E supports SDG&E's LIPs proposal, arguing that: "Providing third parties greater flexibility to utilize the measurement methodology that best reflects the performance of a resource should be granted." (PG&E January 13, 2017 Comments at 16.) PG&E also supports SDG&E's proposal to establish a working group. (Id.)¹⁰ Other parties, including the Joint DR Parties,¹¹ CLECA and Office of Ratepayer Advocates (ORA) support the creation of a working group. (Joint DR Parties March 10, 2017 Comments at 3, CLECA March 10, 2017 Comments at 19, ORA March 10, 2017 Comments at 7.)

We direct the creation of a working group on these issues. This working group should be coordinated with the CAISO, and can address all of the weather

¹⁰ On SDG&E's more general proposal to consider how to integrate weather sensitive demand response into the CAISO markets, PG&E recommended that the working group be CAISO-led.

¹¹ The Joint DR Parties are Comverge, Inc., CPower, EnerNOC, Inc., and Energy Hub.

sensitive DR issues, including treating weather sensitive DR as a variable resource, RA capacity accounting for weather sensitive DR, and use of the LIPs methodology. The working group will submit its analysis and recommendations to the proceeding considering 2019 RA compliance.

9.5. Maximum Cumulative Capacity Buckets

Several parties proposed to create a new 2-hour Maximum Cumulative Capacity category or “MCC bucket,” as they have become known. In general terms, these proposals would allow for a resource to qualify as an RA product if it could sustain energy output for a minimum of two hours, which is shorter than the current minimum requirement of four consecutive hours. SCE, SolarCity Corporation (SolarCity), California Energy Storage Alliance (CESA) and the Joint DR Parties all propose variations on this idea (SCE December 16, 2016 Proposal at 6, SolarCity December 16, 2016 Proposal at 2, Joint DR Parties December 16, 2016 Proposal at 2), while the Commission’s Energy Division has proposed to eliminate the MCC bucket framework (Energy Division December 16, 2016 Proposal at 4).

While there is interest in these proposals, and parties see potential benefits, parties have also expressed concerns and identified potential problems. (CAISO January 17, 2017 Comments at 3, SDG&E January 17, 2017 Comments at 25-26, NRG January 17, 2017 Comments at 2-3). Given the number of proposals and related issues that are raised by the proposals, and the wide variety of opinions (and concerns) raised by the parties, it is premature to adopt a two-hour product here. Similarly, it appears to be most prudent to not eliminate the MCC bucket framework at this time. These are issues that require additional analysis, focus and refinement before implementation.

9.6. Existing Demand Side Load Impacts

Energy Division proposed that each utility provide historical hourly demand side load impacts (for DR, distributed generation, and energy efficiency) to energy service providers and community choice aggregators that serve load in the utility's service territory, and that each utility submit these load impacts to the California Energy Commission and CPUC. (Energy Division December 16, 2016 Proposal at 14-15.) The utilities, ORA and The Utility Reform Network (TURN) generally supported this proposal, with the caveat that more work was needed prior to implementation. (*See, e.g.,* PG&E January 13, 2017 Comments at 14-15; ORA March 10, 2017 Comments at 11-12.) SDG&E suggested the establishment of a working group on this proposal. (SDG&E March 10, 2017 Comments at 4-5.)

We direct the creation of a working group on this issue. The working group will submit its analysis and recommendations to the proceeding considering 2019 RA compliance.

9.7. Seasonal Local Resource Adequacy

PG&E proposes that local RA needs be set on a seasonal, rather than annual basis, starting for the 2019 RA compliance year. (PG&E February 24, 2017 Proposal at 16.) While some parties support this proposal, or at least support doing a preliminary evaluation of it (*see, e.g.,* AReM January 13, 2017 Comments at 4), the CAISO expressed concerns about its value. (CAISO January 13, 2017 Comments at 13.) PG&E suggested that the Commission's Energy Division and the CAISO establish a working group to investigate this issue more fully, and present the results in next year's RA cycle. (PG&E March 24, 2017 Comments at 12.) We direct the creation of a working group on this issue. The working

group will submit its analysis and recommendations to the proceeding considering 2019 RA compliance.

9.8. Local Resource Counting Issues

PG&E made two proposals seeking clarification of the treatment of local resources. One proposal was:

[T]hat the Commission clarify/amend the RA rules so that LSEs are allowed to use local resources in their monthly system RA showings that may differ from the local resources that had been shown in the annual local RA showing, so long as the new resource(s) are in the same local area as the previous resource was, and have at least the same NQC value.” (PG&E February 24, 2017 Proposal at 13-14.)

As noted by PG&E, an informal process has been established for handling local resource changes between the year-ahead and month-ahead process. (Id. at 13.) In developing the 2018 RA Guide Energy Division will outline a less burdensome process for swapping out local resources.

The second proposal was that the Commission clarify that: “[U]nder the Commission’s rules, all RA resources that are located in a local area are required to be shown as such, and that they are thus classified as local RA resources.” (Id. at 20.) Since the establishment of the local RA framework in D.06-06-064, the Commission’s RA program has counted all resources in a local area toward meeting local RA requirements. In drafting the 2018 RA Guide, Energy Division will make clear that resources physically located in an identified locally constrained area count as local RA capacity.

9.9. Remaining Issues

Quite a few other issues were raised by the parties, which were addressed in varying levels of detail. Some of these issues may have the potential for improving the RA process, but are not ready to be implemented. The

Commission may choose to address those issues further in this proceeding or a successor to this proceeding. At this time, however, any proposal or issue that is not expressly approved by this decision is not adopted.

10. Comments on Proposed Decision

The proposed decision of ALJ Allen in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 14, 2017, and reply comments were filed on June 19, 2017.

SDG&E identifies two calculation errors in the proposed decision:

First, the PD's calculation of the net qualifying capacity ("NQC") of solar and wind facilities located in each local area is based upon 2017 NQC values rather than being calculated using the ELCC methodology adopted elsewhere in the PD. The LCR Study (upon which the PD's calculations are based) relied on 2017 NQC values for solar and wind facilities because the ELCC methodology was not adopted at the time the CAISO conducted the LCR Study.

Application of the ELCC methodology to calculate the NQC values of resources in the San Diego/Imperial Valley local area results in a reduction of available capacity in the local area by 223 MW.

[...]

The PD errs in that it fails to adjust the available capacity to reflect application of the ELCC methodology. To account for adoption of the Energy Division's ELCC methodology, the PD must be modified to reflect a reduction of available local capacity in all local areas, which includes a reduction of 223 MW in the San Diego/ Imperial Valley area.

The second factual/technical error contained in the PD is its incorrect assumption regarding the availability of all Encina Units other than Unit 1 in the San Diego/Imperial Valley local area, which adds a total of 859 MW of available capacity in the local area. Under

the requirements of the State Water Resources Control Board's ("SWRCB") *Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* ("OTC Policy"), Encina is required to demonstrate compliance with stringent water use standards by December 31, 2017. To date, Encina has not demonstrated that compliance with these standards has occurred or will occur by the OTC Policy compliance deadline, nor has it obtained an extension of the deadline.

Since there is no indication that Encina will either comply with the OTC Policy or obtain an extension from the SWRCB prior to the October year-ahead RA compliance filing, it is not reasonable to assume that Encina will be available for procurement for the 2018 compliance year. Thus, Encina was improperly included in the calculation of resources available to provide local RA capacity in 2018, and the PD's estimation of total available MW of local capacity based upon the LCR Study data is erroneous. The PD should be revised to reduce the total MWs of available local capacity in the San Diego/Imperial Valley local area by 859 MW to reflect the unavailability of Encina in 2018. (SDG&E Comments on Proposed Decision at 2-4, footnotes omitted.)

SDG&E is correct. The corresponding numbers have been changed on the table "2018 Local Capacity Requirements" in Section 3 above.

PG&E argues that in order to respond to the increasing number of LSEs and the increasing volume of load that they serve, that the proposed decision should be modified to add the requirement that, for the current RA year, the August load forecast be changed from 'optional' to 'mandatory.' (PG&E Comments on Proposed Decision at 3.) PG&E is correct that there is significant load migration occurring, and this adversely affects the accuracy of the load forecasts used for RA purposes. PG&E's argument has merit, and the proposed decision has been modified to include this requirement.

Other parties offered a range of comments. In response, minor clarifying changes have been made.

11. Assignment of Proceeding

Commissioner Liane Randolph is the assigned Commissioner and Peter V. Allen is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The CAISO recommended total local capacity requirements for all local areas of 25,207 MW and 24,999 MW for existing capacity needed in 2018.
2. Because of resource deficiencies, the existing capacity needed for LCR is 24,400 MW in 2018.
3. The CAISO recommended system-wide flexible capacity requirements for Commission-jurisdictional load-serving entities ranging from 10,156 MW (July 2018) to 14,612 MW (December 2018).
4. The CAISO did not meet the Commission's deadlines for submission of its final LCR and FCR studies.
5. It is not practical to adopt a durable flexible capacity requirement at this time.
6. It is not practical to adopt a multi-year RA requirement at this time.
7. Public Utilities Code Section 399.26(d) directed the Commission to implement the use of the ELCC of wind and solar energy resources to establish the RA contribution.
8. Determining how to implement ELCC has been complex and lengthy.
9. Energy Division and Calpine have developed similar approaches to implementing ELCC.

10. Energy Division's second proposed methodology eases the transition to ELCC by removing the effect of behind-the-meter photovoltaic solar generation on the overall solar ELCC.

11. Load migration is adversely affecting the accuracy of load forecasts used for RA purposes.

12. Changing the August load update from optional to mandatory would improve the accuracy of load forecasts used for RA purposes.

13. Other issues were raised by the parties that are still under development, or are otherwise not quite ready for implementation, but that could benefit from further development and refinement that may result in implementable proposals in the future.

Conclusions of Law

1. The CAISO's recommended total LCR for all local areas of 25,207 MW and 24,999 MW for existing capacity needed in 2018 should be adjusted to reflect resource deficiencies.

2. The existing capacity needed quantity for LCR of 24,400 MW in 2018 should be adopted.

3. The CAISO's recommended system-wide FCR for Commission-jurisdictional LSEs ranging from 10,156 MW (July 2018) to 14,612 MW (December 2018) should be adopted.

4. The CAISO's late submission of its final LCR and FCR studies creates potential legal and practical problems.

5. A durable FCR should not be adopted at this time.

6. A multi-year RA requirement should not be adopted at this time.

7. Implementation of an ELCC approach is consistent with Pub. Util. Code § 399.26(d), is supported by the record, and should be adopted.

8. Energy Division's second proposed methodology for implementing ELCC should be adopted.

9. The August load update should be made mandatory instead of optional for all Commission-jurisdictional LSEs.

10. Energy Division should use informal processes, such as working groups, to further develop and refine issues that were raised but that are not ready for implementation at this time.

O R D E R

IT IS ORDERED that:

1. The total existing capacity needed for the local capacity requirement for all local areas of 24,400 megawatts in 2018 is adopted.

2. The California Independent System Operator recommended system-wide flexible capacity requirement for Commission-jurisdictional load-serving entities ranging from 10,156 megawatts (MW) (July 2018) to 14,611 MW (December 2018) is adopted.

3. The Commission will explore ways to resolve the problems caused by the late submission of the final local capacity requirement and flexible capacity requirement studies.

4. A durable flexible capacity requirement is not adopted at this time.

5. A multi-year resource adequacy requirement is not adopted at this time.

6. Energy Division's second proposed methodology for implementing effective load carrying capacity is adopted.

7. The August load update is made mandatory for all Commission-jurisdictional load serving entities.

8. Energy Division shall coordinate the creation of working groups on the issues of Removal of the Path 26 Constraint, Weather Sensitive Demand Response, Existing Demand Side Load Impacts, and Seasonal Local Resource Adequacy.

9. Energy Division shall either hold a joint workshop with the California Independent System Operator or coordinate the creation of a working group to clarify the definition of “dispatchable.”

10. Energy Division shall clarify the interchangeability and classification of local resources via the annual Resource Adequacy Compliance Guide.

11. Energy Division shall coordinate their informal processes with the California Independent System Operator and other parties and agencies as necessary and appropriate.

12. Rulemaking 14-10-010 is closed.

This order is effective today.

Dated June 29, 2017, at San Francisco, California.

MICHAEL PICKER

President

CARLA J. PETERMAN

LIANE M. RANDOLPH

MARTHA GUZMAN ACEVES

CLIFFORD RECHTSCHAFFEN

Commissioners

I reserve the right to file a concurrence.

/s/ MARTHA GUZMAN ACEVES

Commissioner

Appendix A

Background on Modeling Processes Used to Create Monthly ELCC Values:

Monthly Effective Load Carrying Capability (ELCC) studies are required to set the ELCC values of wind and solar electric generators. ELCC values based on a study of just the peak months are not sufficient to determine ELCC values for offpeak months. Monthly ELCC values rest on a baseline monthly Loss of Load Expectation (LOLE) or Loss of Load Hours (LOLH) study. LOLE and ELCC value of individual generators will differ each month, particularly for generators whose output is dependent on weather. The resulting performance of a portfolio of electric demand and electric generators will thus differ significantly between months of the year, and in each month the relative value of generators will also vary.

The calibration and sequence of these studies depends on the objectives of the study. Both Calpine and Energy Division followed a similar study plan, with some significant differences. In their February 24, 2017 proposals, Calpine and Energy Division each proposed creation of monthly ELCC values for solar and wind generators. Essential differences between the final modeling processes of Calpine and Energy Division focused in two areas – definition of reliability metric and targeted reliability level (LOLH versus LOLE) and the method of adding/subtracting to measure reliability contribution. These differences appear in steps 1 and 2 in the list below.

Calpine's study produced LOLH values since Calpine did not model the entire year and all hours within the year in chronological order, instead sampling a subset of the days in a year. This difference is important, and means there is no explicit connection between the hours with outage events (there is no direct way of seeing that the hours are connected into the same events), while Energy Division modeled the entire year contiguously. That is why Calpine's results are expressed as LOLH and Energy Division's results are expressed as LOLE.

In addition, Calpine and Energy Division aimed at different monthly LOLE levels to serve as a baseline. Calpine aimed towards a target of 0.0083 LOLH, while Energy Division targeted a LOLE of 0.025 each month, and Energy Division's actual results ranged between 0.02 and 0.03 LOLE each month. Due to the simplicity of Calpine's model, it is not possible to see outage hours as connected and contiguous, and it is hard to see that in several cases, events are multiple hours in length. Energy Division's modeling resulted in LOLE results between 0.02 and 0.03 in each month, but each outage event in Energy Division's modeling averaged 1.5 hours in length. Based on Energy Division's results, Calpine's 0.0083 LOLH target would translate to a LOLE of 0.004 and would be roughly one fifth of the LOLE resulting from Energy Division's modeling. This difference likely results in a small decrease in the ELCC of solar generators in Calpine's modeling relative to Energy Division's results.

Finally, Calpine took out capacity, then added or subtracted load in each hour until the reliability level returned to the desired range. Energy Division added or subtracted Perfect Capacity to return the reliability level to desired range. This difference is small and insignificant.

Energy Division offered two proposals this year. The first proposal measures the effect of BTM PV solar together with RPS supply side solar on average solar ELCC levels, while the second proposal seeks to remove the effect of BTM PV solar on the overall solar ELCC by estimating it and backing it out of the solar ELCC value.

Figure 1 below illustrates the effect of BTM PV on overall solar ELCC in Energy Division’s proposal by comparing ELCC of solar in three previous Energy Division ELCC proposals. Each proposal represents an increasing level of solar generators and a decreasing ratio of Perfect Capacity to solar generators in MW. In essence, removing the BTM PV from the fleet of solar generators is to move backwards up a descending curve of value, thus the ELCC increases to roughly the average of Energy Division’s March 2016 proposal and the current February 2017 proposal.

Table 1 below compares ELCC percentages from ED’s proposals and Calpine’s proposal. In the spring months, ED staff produced slightly lower solar percentages than Calpine did, but significantly higher wind percentages.

Figure 1 Effect of BTM PV on Solar ELCC

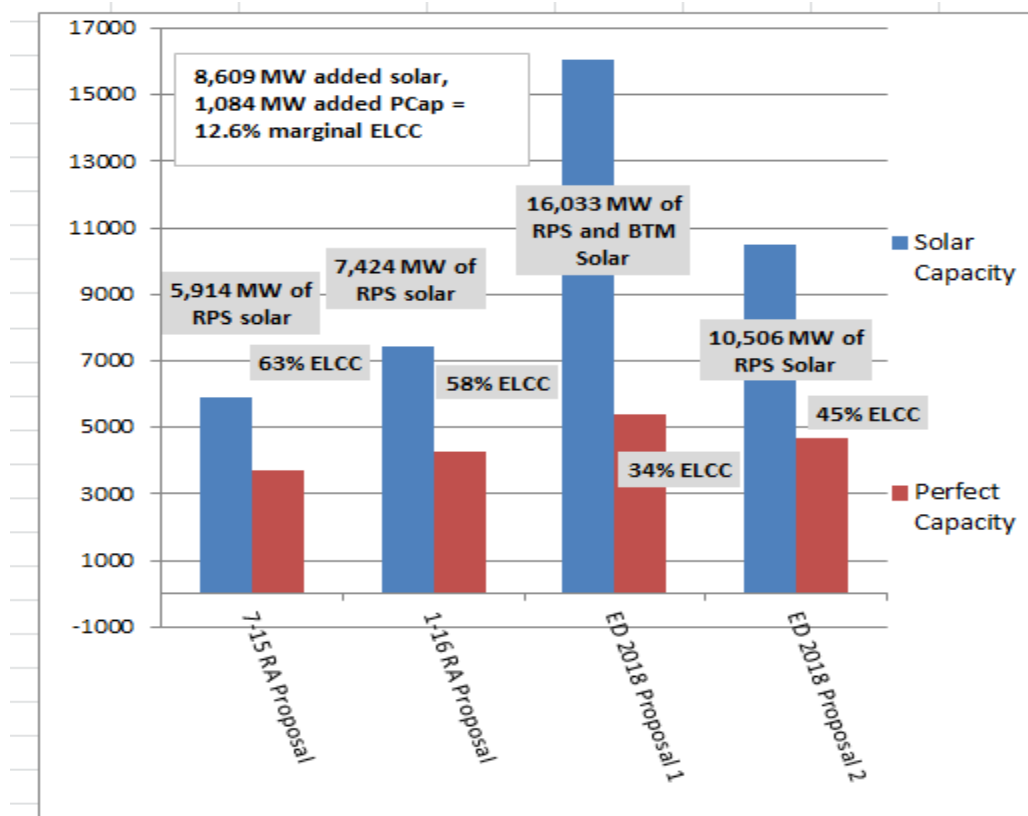


Table 1 Comparison of ELCC percentages between ED's and Calpine's Final Proposals

	Energy Division's results			Calpine's results	
	Solar Proposal 1	Solar Proposal 2	Wind	Solar ELCC	Wind ELCC
MW Install	16,033	10,506	6,891	15,887	5,592
Jan	0.0%	0.0%	11.3%	0.0%	13.3%
Feb	1.8%	2.4%	17.3%	1.3%	15.2%
Mar	7.8%	10.4%	18.3%	6.1%	9.7%
Apr	24.8%	33.2%	31.4%	25.6%	18.3%
May	22.8%	30.5%	30.6%	32.7%	27.3%
Jun	33.5%	44.8%	47.5%	37.8%	36.3%
Jul	31.2%	41.7%	29.7%	33.9%	41.4%
Aug	30.7%	41.0%	26.5%	31.2%	30.6%
Sep	25.0%	33.4%	26.5%	25.9%	21.0%
Oct	22.0%	29.4%	8.8%	21.5%	11.6%
Nov	3.1%	4.1%	8.4%	3.7%	7.5%
Dec	0.0%	0.0%	15.2%	0.0%	12.7%

Monthly ELCC Study Process:

Monthly Effective Load Carrying Capability (ELCC) studies are required to set the ELCC values of wind and solar electric generators. ELCC values based on a study of just the peak months are not sufficient to determine ELCC values for offpeak months. Monthly ELCC values rest on a baseline monthly Loss of Load Expectation (LOLE) or Loss of Load Hours (LOLH) study. Other reliability metrics (such as Expected Unserved Energy or EUE) may be studied, but LOLE and LOLH will be the preferred means of communicating reliability. In the event studies produce LOLH or other results, parties shall provide a means to compare to LOLE results. Parties must provide a good explanation for their chosen monthly reliability targets and metrics, whether parties choose to equalize reliability across each month or decide to focus reliability risk in one part of the year. Study proponents must be able to communicate to parties to the proceeding why months were modeled as chosen, and how reliability was assessed in each month.

Once monthly reliability baselines are studied and determined, study proponents must produce a study of the monthly ELCC of the whole portfolio of electric generators in the class being studied (the Portfolio ELCC) to serve as a baseline control total for each subcategory or locational group within the larger portfolio being studied. Study proponents must demonstrate the order and means of breaking the Portfolio ELCC down into standalone ELCC values for each technology based or locational subcategory within the larger studied portfolio. Studies must demonstrate the order and means of studying ELCC. Studies must demonstrate if ELCC was quantified as a comparison to load or capacity, and if capacity, was it Perfect Capacity or existing real capacity.

Once Portfolio ELCC is determined, standalone ELCC values are studied, by studying one category or subcategory of electric generator at a time, and individually in each month. Standalone monthly ELCC values are totaled by month and the total is compared to the corresponding month's Portfolio ELCC, and the standalone values are either lowered or raised to equal the corresponding month's Portfolio ELCC. This is called the Diversity Adjustment.

Monthly ELCC of wind or solar generators in the CAISO area will be established pursuant to the following steps:

1. Conduct a Monthly LOLE or LOLH study. Choose a metric to target (LOLE or LOLH) and a reliability level for each month that represents the desired level of reliability that planners are attempting to have. Conduct an hourly reliability simulation representative of each month of the year with projected loads and expected resources that results in the desired monthly reliability level in each month. If results are either more or less reliable than desired, capacity or load is to be added or subtracted until each month's reliability results are in the desired range.
2. Conduct a Monthly Portfolio ELCC study. Remove all wind and solar electric generation facilities inside the CAISO aggregated region. Add or remove Perfect Capacity or load in each month individually until the resulting reliability level is back to the desired range. The amount of Perfect Capacity in MW (or load in MW) added is equal to the Portfolio ELCC of all wind and solar generators.
3. Perform ELCC modeling on each category individually
 - a. Add back wind generators and leave solar generators removed. Add blocks of load or take away blocks of Perfect Capacity iteratively from each month until reliability levels are within the desired range each month. The result is the standalone ELCC of solar generators. Record the monthly levels of Perfect Capacity modeled.
 - b. Perform Step A in reverse by adding back solar generators and removing wind generators. Remove blocks of Perfect Capacity iteratively from each month. Remove Perfect Capacity until the reliability level again falls within the desired range in each month. The result is the standalone ELCC of wind generators. Record the monthly levels of Perfect Capacity or added load modeled.
4. Add the standalone ELCC of wind and solar generators, and compare the total to the Portfolio ELCC calculated earlier. The difference (either positive or negative) is the diversity adjustment. (The diversity adjustment will be negative when the standalone ELCC values total greater than the Portfolio ELCC, and are the result of modeling a category of generator while another category of generators in the Portfolio ELCC was present, and some of the reliability contribution it imparts is applied as diversity. In that case, diversity must be removed.) Allocate the diversity adjustment to either wind or solar generators by prorating to the proportion of wind and solar standalone ELCC in each month.

5. Energy Division's second proposal adds a step here: Energy Division backs out the effect of BTM Solar on the overall RPS supply side solar ELCC. Energy Division staff compares the ELCC of solar generators without BTM PV in the fleet (taken from the March 2016 RA ELCC proposal) to the ELCC of solar with BTM PV included from this February 2017 RA proposal. That difference represents the amount of Perfect Capacity that is equivalent to the additional supply side solar added since March 2016 as well as all BTM PV installed that has until now not been included in modeling. Prorating the additional Perfect Capacity to the portion of the new solar that is BTM PV will represent the added Perfect Capacity for the BTM PV, and when removed represents just the Perfect Capacity needed for the incremental new supply side solar added. (Calpine prorates the effect of BTM PV over the entire solar fleet, not just the incremental marginal new solar, and also grosses up the BTM PV for the 15% PRM to create the ELCC for BTM PV.)
6. Take the ELCC MW values that are the result of the modeling for each month, and divide them by the total nameplate installed MW of that technology, and the resulting monthly percentage values represent the ELCC percentages that are applied to the nameplate MW values of each individual generating facility to create the Qualifying Capacity of the generator. (Calpine proposes a methodology that allocates ELCC value individually to generators based on historical generation data)
7. Any further steps to create locational factors to break up wind and solar further into location or sub technology specific factors would follow from this point, and thus would be added as steps 7 and on. Future Monthly ELCC studies would require restarting the sequence of studies from Step 1.

(End of Appendix A)

**Concurring Opinion of Commissioner Martha Guzman Aceves and
Commissioner Carla J. Peterman
Decision Adopting Local and Flexible Capacity Obligations for 2018 and
Refining the Resource Adequacy Program**

R.14-10-010

June 29, 2017

In concurrence with our decision today we emphasize that we expect load serving entities to use preferred resources to the greatest extent possible when meeting resource adequacy obligations.

California has had a longstanding commitment to filling energy needs first with preferred resources, including energy efficiency, demand response, storage, and renewables. Only then – if preferred resources fail to satisfy demand or otherwise cannot fulfill reliability needs – can utilities rely on conventional electricity supply. For over a decade we emphasized this policy through the loading order, which was first set forth in the 2003 Energy Action Plan and been subsequently reiterated in numerous Commission decisions.¹

As California continues transitioning the electricity sector to higher amounts of renewables and other zero-carbon resources to meet our energy needs, we will optimize resource portfolios using integrated resource planning. At the same time we must also ensure these resources contribute to and are accounted for in grid reliability planning. Our resource adequacy programs

¹ Cal. Pub. Util. Code § 454.5(b)(9)(C) (2017); Energy Action Plan 2008 Update at 1; see also D.14-03-004 at 13-14 (detailing history of the loading order), 16 (“We maintain our commitment to the Loading Order in this decision.”)

must evolve to fully capitalize on California's significant investments in renewable and other clean resources.

Currently, nearly all flexible capacity requirements and the vast majority of local capacity requirements are met through contracts with natural gas fueled power plants. Clean resources must contribute to and can be counted towards all forms of reliability, not just to meet system peak electricity demand in summer. Accordingly, we concur and emphasize that, consistent with longstanding Commission precedent recognizing the loading order and California's ongoing commitment to reducing greenhouse gas emissions, we expect the utilities' resource adequacy procurement to maximize contracting with preferred resources first.

Dated July 10, 2017, San Francisco, California.

/s/ MARTHA GUZMAN ACEVES

Martha Guzman Aceves
Commissioner

/s/ CARLA J. PETERMAN

Carla J. Peterman
Commissioner